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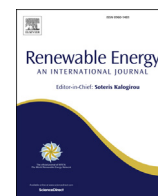
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Impact of technical and economic uncertainties on the economic performance of a deep geothermal heat system



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ABSTRACT

This paper presents a techno-economic analysis of a deep, direct use geothermal heat system in a conductive geological setting (Groningen, NE Netherlands). The model integrates the previously discussed uncertainties of the initial reservoir state, geological and operational conditions with the economic uncertainties. These uncertainties are incorporated in the form of probability distributions and 20,000 iterations of the model are performed over a project lifetime of 40 years. A combination of Ex-Ante and Ex-Post criteria are used to evaluate the economic performance of the system based on the Net Present Value (NPV), Levelised Cost of Heat (LCOH) and Expected Monetary Value (EMV). The sensitivity analysis highlights the load factor (effective flowrate) as the most important parameter for the economic performance and energy costs. However, the differences between the NPV and LCOH sensitivities highlight the importance of using both metrics for the economic performance of such systems. The presented project remains economically challenging, exhibiting a 50% probability of marginal revenues over its lifetime. Systematic insights are drawn with regard to potential improvements of technical and economic aspects of such geothermal heat systems.

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1. Introduction

District heating and heat energy networks are gaining importance in the provision of renewable energy [1–3]. At the same time market penetration of direct use geothermal energy remains relatively restricted [4] and a large potential for direct use geothermal remains untapped [5].

Geothermal energy is considered as a mainstream technology from a technological paradigm perspective [6]. Implementation of geothermal systems is still expected to accelerate in the near future [7] and possibly saturate by 2030 [6]. The number of direct use installations for geothermal energy and investments in geothermal projects have continuously increased in the 21st century, but the development rates are deemed slow [7].

As the scientific understanding of a diversity of low enthalpy fields and analysis methods are evolving [8–12], the interaction between the technical and the economic aspects becomes more pertinent for successful project implementation and wider

dissemination of installed deep geothermal systems for direct use. The importance and impact of technical and economic parameters remains crucial for the realization of planned systems.

Promoting the sustainability agenda within renewable energy projects encourages the efficient use of geothermal resources [13]. Previous research has highlighted points of exergy destruction that are important for optimizing the energetic efficiency of existing systems [14,15]. In order to expand installed geothermal capacity, project level studies are needed to address the complexities and inherent uncertainty of geothermal field development [5,13].

Economic feasibility is identified as the main hindering aspect of direct use geothermal systems, with payback periods extending up to 33 years [16]. Drilling is considered a major cost factor and increasing the success rates would benefit geothermal project developments [16]. Additionally, the economics of geothermal energy production (electricity or heat) are usually addressed in a top down manner [17–19], contrary to the commonly accepted need for project level geotechnical studies. Thus, while the insights from a top down analysis are valuable, they do not clarify the interplay between the geological context, the specific economic conditions of a project and the contextual parameters, such as the regulatory

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framework with its possible incentives and restrictions [3].

Due to the high initial costs and uncertainties related to geothermal development [20], scenario analysis is essential for understanding the economic viability of projects [17,21]. A recent study has analysed the effect of doublet well spacing on the Net Present Value (NPV) of a geothermal doublet in the West Netherlands Basin (WNB) [22]. Moreover, the interference between multiple systems and the related economic impact has also been studied [23]. However, literature on direct use, deep geothermal projects lacks an analysis that incorporates both technical and economic uncertainty to the assessment of energy generation costs. Moreover, there is no clear prioritization between the two in the form of a sensitivity analysis at the project level; no bottom-up cost estimation is presented.

In this paper a techno-economic model is presented based on the Groningen geothermal project (Fig. 1). It builds on previous work regarding initial state, geological and operational uncertainty [24] and incorporates the insights regarding resource efficiency and coupling of a direct use geothermal system to heat networks [25]. In this work economic and project development uncertainties are further included in order to establish a tighter linkage between technical and economic aspects for the Groningen geothermal project.

The analysis employs a novel, bottom-up economic analysis of a direct use geothermal system in a conductive geological setting.

The economic feasibility is analysed by means of three economic indexes in tandem, namely the Levelized Cost of Heat (LCOH), Net Present Value (NPV) and Expected Monetary Value (EMV) indexes; it is thus addressing the center of the renewable energy nexus, linking geothermal technology with the policy/incentive framework. Moreover, it includes scenario analysis and project level uncertainties for both the technical, as well as the economic parameters considered. Lastly, it presents a structured, ranked influence of both technical and economic parameters to project economics; it thus generates comprehensive insights regarding the development of direct use, deep geothermal systems in conduction dominated geological settings on a project level.

2. Methods and model description

The results are evaluated using Ex-Ante (beforehand) and Ex-Post (afterwards) criteria. The Ex-Ante criteria (well failure) lead to a project stop. After that point further computations are not carried out. Ex-Post criteria include the LCOH and the project NPV at the end of the project period, as well as the Expected Monetary Value (EMV) of the project.

The model is developed by making use of the Monte Carlo Simulation software GoldSim [26]. Uncertainty regarding any of the technical or financial aspects considered is implemented in the model in the form of probability distributions. This allows for an Ex-

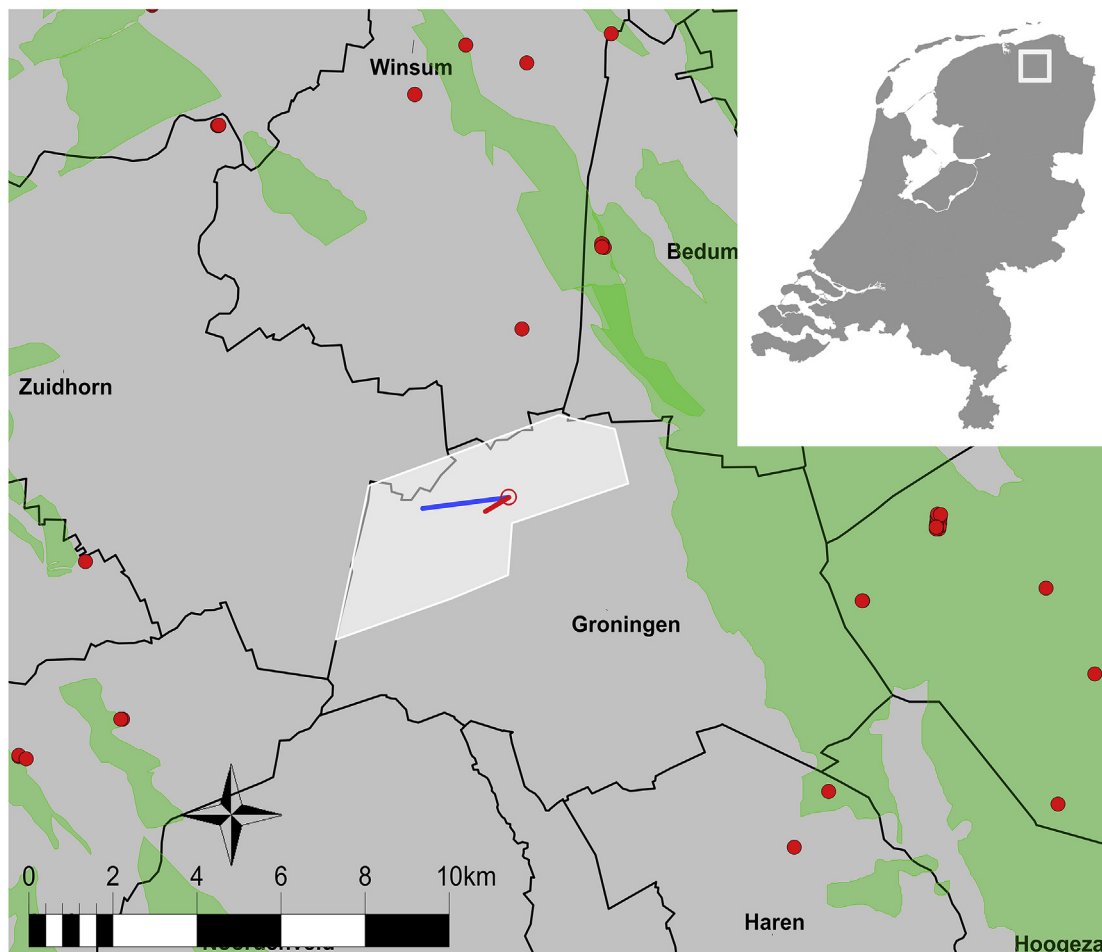


Fig. 1. Location of the Groningen geothermal project. The white shaded area outlines the geothermal concession, the red and blue lines the injector and producer respectively, the green shaded areas are existing gas fields and the red dots represent existing gas wells. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

Post overall evaluation of the outcomes. The probability characteristics of each module inputs are detailed in the following sections.

2.1. Exploration

The Exploration phase is the initial reconnaissance phase of the project. Interest in generating geothermal energy is identified and initial studies commence. An application for an exploration-drilling license is made and detailed geological studies are carried out. During this phase modelling studies might also be carried out to locate prospective aquifers, estimate reservoir volume and characteristics, forecast energy production and to support system design and dimensioning. Two major elements are of importance, namely the duration of the exploration phase and the attributed cost (Table 1 Exploration).

2.2. Development

The Development phase includes the construction of the heat network, drilling the wells and purchasing equipment necessary for

operating the system. The major capital expenditures for the project occur during this phase (see also 2.4.1.). The model inputs used for this module are summarized in Table 1 Development.

2.2.1. Heat network

The project heat network has a length between 20 and 30 km and has an average cost of 1000 €/m of installed network, including materials.

2.2.2. Drilling

Two different formulas are considered for calculating the well drilling costs. The first is the ThermoGIS equation for well costs [17,18]:

$$C_{well} = s \cdot (0.2 \cdot Z_R^2 + 700 \cdot Z_R + 25000) \cdot 10^{-6} \quad (1)$$

where s is a variable representing the well scaling factor, Z_R is the measured depth (MD) and costs are calculated in euros. An s value of 1.72 is used for the calculations.

The second formula is the geothermal well cost presented by Lukawski et al [27]. The authors here mention that despite

Table 1

Model inputs for the modules of exploration, development, production and economics. Bold values indicate the base case for the sensitivity analysis presented in the results section.

Module	Element	type	distribution	resampled	value	Unit
Exploration	Exploration phase duration	probability	triangular	once at iteration start	3–4–5	yr
	Exploration phase cost	probability	triangular	once at iteration start	180– 200 –280	k€/yr
Development	network length	probability	uniform	once at iteration start	20–30	km
	network cost	probability	triangular	once at iteration start	800– 1000 –1200	€/m
	ESP cost	data	—	—	800	k€
	heat exchanger	data	—	—	100	k€
	gas separation unit	data	—	—	210	k€
	producer well contingency	probability	triangular	once at iteration start	100– 120 –120	%
	injector well contingency	probability	triangular	once at iteration start	92.5– 100 –107.5	%
	production well MD	data	—	—	3980	m
	injection well MD	data	—	—	4562	m
	production well success	probability	boolean	once at iteration start	70% success	%
	injection well success	probability	boolean	once if successful production well	90% success	%
	drilling insurance	data	—	—	1	M€
	abandonment cost per well	data	—	—	1	M€
	drilling location cost	probability	triangular	once at iteration start	1.5–1.5–2	M€
	development duration	probability	triangular	once at iteration start	2–3–4	yr
	Injection temperature	probability	discrete	once at iteration start	equal probability 40 /55/70	°C
	Reservoir Permeability	probability	discrete	once at iteration start	25%:P90 50%: P50 25%: P10	—
Production	Production temperature	data	—	—	120	°C
	Doublet temperature loss	probability	uniform	daily	min: 2 max: 10	°C
	Desired capacity	probability	discrete	once at iteration start	equal probability 10/ 12.5 /15	MW
	High temperature household equivalents	data	—	—	10000	—
	LT houses (fraction of HT)	data	—	—	15	%
	transmission efficiency	probability	normal	daily	mean: 85 , s.d.: 3.5	%
	Heat exchanger efficiency	probability	normal	daily	mean: 90 , s.d.: 1.5	%
	Pump efficiency	probability	normal	daily	mean: 65 , s.d.: 2.5	%
	Pump failure rate	probability	normal	resampled at ESP installation	mean: 0.2 , s.d.: 0.04	1/yr
	Reservoir gas saturation	probability	discrete	once at iteration start	equal probability 5/10/15	%
	Reservoir pressure depletion	probability	discrete	once at iteration start	equal probability 0 /100/200	bar
	Gas production	probability	normal	daily	based on reservoir permeability and gas saturation (see Appendix B)	m ³ /m ³
Economics	OpEx%	data	—	—	5	%/yr
	inflation rate	data	—	—	1.5	%
	discount rate	data	—	—	7	%
	interest rate	data	—	—	2.5	%
	depreciation rate	data	—	—	5	%/yr
	gas heat price	probability	normal	daily	mean: 23.19 , s.d.: 0.10	€/GJ
	geothermal to gas heat price ratio	data	—	—	90	%
	natural gas producer price	probability	normal	daily	mean: 0.25 , s.d.: 0.01	€/m ³
	subsidy amount	data	—	—	0.045	€/kWh
	electricity price	probability	normal	daily	mean: 0.08 , s.d.: 0.01	€/kWh
	connection fee	data	—	—	1000	€
	usage fee	data	—	—	300	€/yr

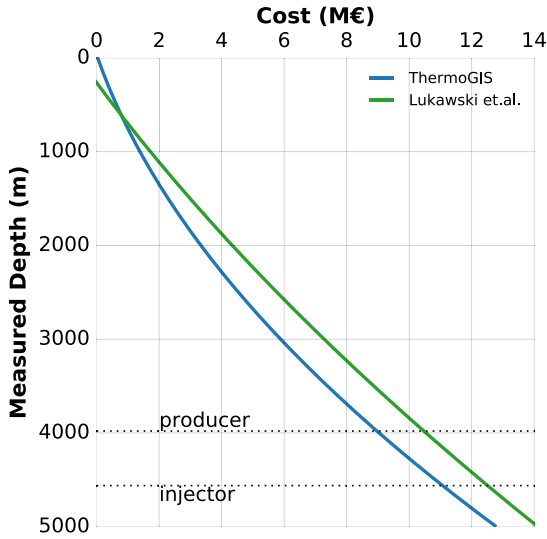


Fig. 2. Well cost calculation formulas considered. Specifications of the wells, as well as their trajectories are derived from the Groningen project [24,28].

differences in complexity, geothermal and oil wells have similar costs. The authors do however provide a geothermal specific cost formula and recommend calculating cost on an individual well basis:

$$C_{well} = 1.72 \cdot 10^{-7} \cdot Z_r^2 + 2.3 \cdot 10^{-3} \cdot Z_r - 0.62 \quad (2)$$

where Z_r represents measured depth (MD) and the costs are in million dollars. Dollars are converted to euros according to a rate of 0.93 €/€\$.

Due to the small differences between the two formulas in calculating the well drilling costs (Fig. 2), only the ThermoGIS formula is used in the model in this paper.

In addition to the calculated well drilling costs, a contingency is added to cover possible delays or difficulties that could be encountered during drilling and could increase the overall cost. It is assumed that the injector is drilled first therefore the injector contingency can only increase the costs. The drilling of the producer that follows could potentially benefit from the insights of the first well, therefore the contingency could result in either a reduction or increase of its calculated costs (see also Table 1 Development).

The wells are insured against technical failure and/or suboptimal performance after they have been drilled [29] and the insurance premium is included in the cost. Additional to the well cost some expenses are also made for the preparation of the drilling location and surface facilities around the wells.

Furthermore, successful well drilling is assigned to a certain probability. This probability only takes into account the technical success rate (70% for successfully drilling to a Rotliegend target) in the Netherlands and is based on historical gas well data [30]. After a successful first well (injector) we consider the success rate of the second well to increase to 90% (see Table 1 Development). The combined Probability Of Success (POS) for the doublet is therefore 63%. In the event of a failure for the first well, or of a successful first well and a failed second well, the project stops a year later.

2.2.3. Equipment

Necessary for the operation of the geothermal system are an Electrical Submersible Pump (ESP), a heat exchanger and a gas separation unit and these units are acquired during the

development phase.

2.3. Production and operation

This module computes the generated heat, the possible gas produced by the system and the doublet pressure levels. Reservoir permeability, gas saturation and pressure depletion are differentiated in three values each, as discussed in previous work [24]. Inputs are summarized in Table 1 Production.

2.3.1. Heat production

The capacity of the doublet is defined according to:

$$Cap_{eff} = Cap_{inst} \cdot (\eta_{exch} \cdot \eta_{transm}) \quad (3)$$

where Cap_{eff} the effective maximum power output of the doublet (after the efficiency losses), Cap_{inst} is the doublet capacity, η_{exch} the heat exchanger efficiency and η_{transm} the transmission efficiency.

In addition to the efficiency losses in the exchanger and transmission the heat demand exhibits a seasonal variation on a yearly basis. The predicted hourly demand is shown in Fig. 3a. In accordance with the doublet capacity, only part of the demand is covered by the geothermal system; for this part the average monthly values are computed and the ratio of the monthly demand to the maximum demand covered by the geothermal system (Fig. 3b) is used to scale the production level accordingly by regulating the flow rate.

Consequently, the required flow rate level is calculated according to:

$$Q = \left(\frac{Cap_{eff}}{\Delta T \cdot C_{brine}} \right) \cdot f_{m_{seasonal}} \quad (4)$$

where Q is the flowrate (m^3/s), ΔT is the temperature difference between producer and injector wells, C_{brine} the volumetric heat capacity of the brine ($J/m^3 \cdot K$) and $f_{m_{seasonal}}$ is the seasonal demand at month m . The brine volumetric heat capacity calculations are detailed in Appendix A.

2.3.2. Pump and pressure

The pressure of the doublet is calculated as a function of the flow rate and the reservoir permeability. The mean values and standard deviations for each discrete flow rate value are inferred through statistical analysis of the dataset in Daniilidis et al. (2016), presented in Appendix B. For the same reservoir permeability value, a second order polynomial regression analysis is performed on the dataset (Fig. 4). The derived formula is used to calculate the effective pressure difference between the wells, depending on the reservoir permeability input selected.

The ESP power requirement (in Watts) is calculated as follows:

$$P_{power} = \frac{\rho \cdot g \cdot Q \cdot \Delta p}{p_{hydro} \cdot \eta} \quad (5)$$

In which ρ is the fluid density (kg/m^3), g is the gravity acceleration (m/s^2), Q is the flow rate (m^3/s), Δp is the pressure difference (bar), p_{hydro} the hydrostatic pressure gradient (bar/m) and η the pump efficiency. The ESP is replaced when a failure occurs and the replacement results in a downtime of 15 days during which no energy is being produced. The income not generated due to the downtime is added as part of the pump replacement costs.

2.3.3. Gas production

Gas production as a function of permeability and flow rate is

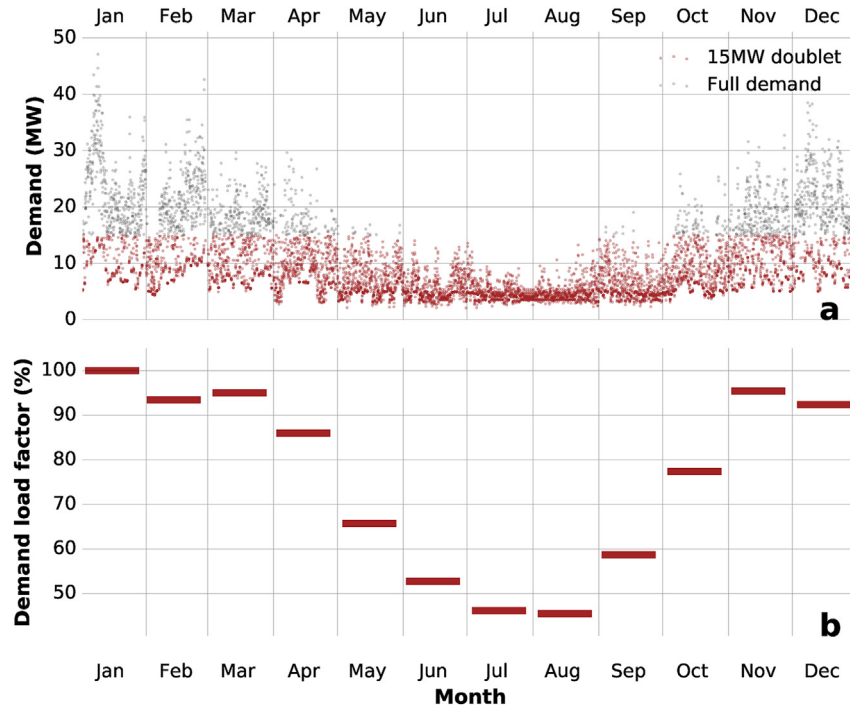


Fig. 3. Hourly demand from the Groningen city project and the part covered by the doublet (a) and respective monthly demand load factor (b).

calculated according to the statistical analysis of the dataset in Daniilidis et al. (2016), presented in Appendix B. Data points and their mean values and standard deviations are also presented in Appendix B. Depending on the reservoir permeability, gas saturation input and the production duration, the corresponding mean values and standard deviations are applied.

2.4. Economics

The Economics module computes all financial indexes based on the inputs regarding expenses and the computed revenues and annuities (Table 1 Economics). A 40 year period is chosen for the model, considering that no production temperature drop is expected within this period [24]; furthermore, the production duration of circa 35 year is considered as a minimum length for developing a geothermal system.

2.4.1. Levelised Cost of heat

The economic outlook of the project is evaluated based on the Levelised Cost Of Heat (LCOH) index and the Net Present Value (NPV) of the project. The LCOH is defined as:

$$LCOH = \frac{\sum_{t=1}^n \frac{CapEx_t + OpEx_t}{(1+r)^t}}{\sum_{t=1}^n \frac{Heat_t}{(1+r)^t}} \quad (6)$$

where $CapEx$ and $OpEx$ are the respective Capital and Operational expenses in year t , r is the discount rate and $Heat$ is the generated energy in year t .

2.4.2. Net Present Value

The NPV is calculated as:

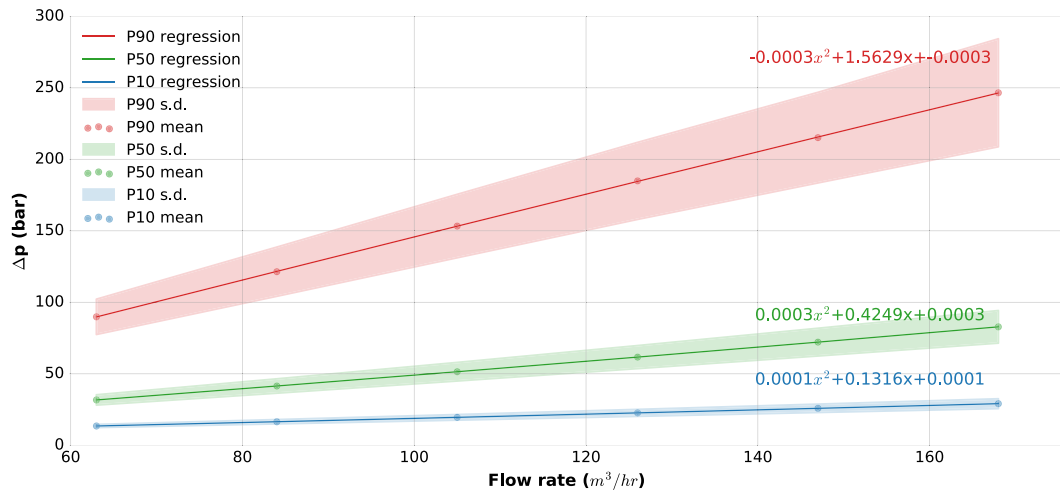


Fig. 4. Analytical formulas for calculating the pressure difference levels in the model. The data are based on the output of the 3D reservoir model for Groningen [24].

$$NPV = \sum_{t=0}^n \frac{CF_t}{(1+r)^t} \quad (7)$$

where CF is the net cash flow (expenses-revenues), t is the year and r is the discount rate.

2.4.3. Expected Monetary Value

The Expected Monetary Value (EMV) is defined as [31,32]:

$$EMV = POS \cdot NPV + (1 - POS) \cdot COF \quad (8)$$

where POS is the Probability of Success for the doublet drilling (with a value of 0.63, see also section 2.2.2 and Table 1 Development) and Cost Of Failure (COF) are the monetary values for a successful and a failed doublet drilling respectively. The COF has a negative value (see also Table 2).

2.4.4. Expenses

The expenses are the sum of the capital and operational expenses. Capital Expenses (CapEx) are discrete investments; these include the costs for the exploration phase, the drilling of the wells, the construction costs for the heat network and drilling facilities, equipment (heat exchanger, gas separator) and the recurring costs for the ESP. The Operational Expenses (OpEx) are computed as a percentage of the CapEx with the pump power electricity added; this is purchased at the electricity price for industrial use (Fig. 5a). The discounted project cash-flow is corrected for inflation, as well as financing interest rate costs. Lastly the depreciation period is calculated based on the depreciation rate. No funding or taxing scheme is considered in our calculations and therefore, depreciation costs are not re-financed.

2.4.5. Revenues

The revenue sources include the income from the delivered

heat, possible produced gas, as well as the income from the SDE+ (Sustainable Duurzame Energieproductie) subsidy scheme for renewable energy in the Netherlands [34]. The subsidy for the delivered heat is for up to 5500 full-load equivalent hours and is available for a maximum period of 15 years [34]. The delivered heat is cascaded at two different levels: high temperature (HT) and low temperature (LT). The cascading scheme assumes that a percentage of the HT heat return temperature is still sufficient to be sold for LT heat usage at half the HT price. Additionally, there is a fixed one-off connection fee and a usage fee per year for the service.

In the Dutch context the heat price of any energy source cannot be higher than the gas produced heat [35]. Therefore, the geothermal heat prices are computed as 90% of the cost for heat generated by gas combustion. The household prices for gas generated heat, gas price for producers and electricity prices are derived statistically from historical data (Fig. 5b and c).

3. Results

The model is run in using 20,000 iterations. Firstly, the energy production and system performance indicators are presented, followed by the economic indexes. Lastly, for a selection of the result indexes a sensitivity analysis is presented.

3.1. Energy production

The annually produced heat demonstrates little variation over the years, with the mean and percentile values exhibiting a clear annual pattern that remains constant throughout the production lifetime (Fig. 6a). Contrary to this, the annual gas production levels (Fig. 6b) prove to be highly uncertain, exhibiting a wide range of values for the percentile interval 90% to Max. This result is in line with the uncertainty level present in the model with regard to gas related variables (e.g. gas saturation, gas production volume, see also Table 1 Production). The cumulative data for heat and gas are

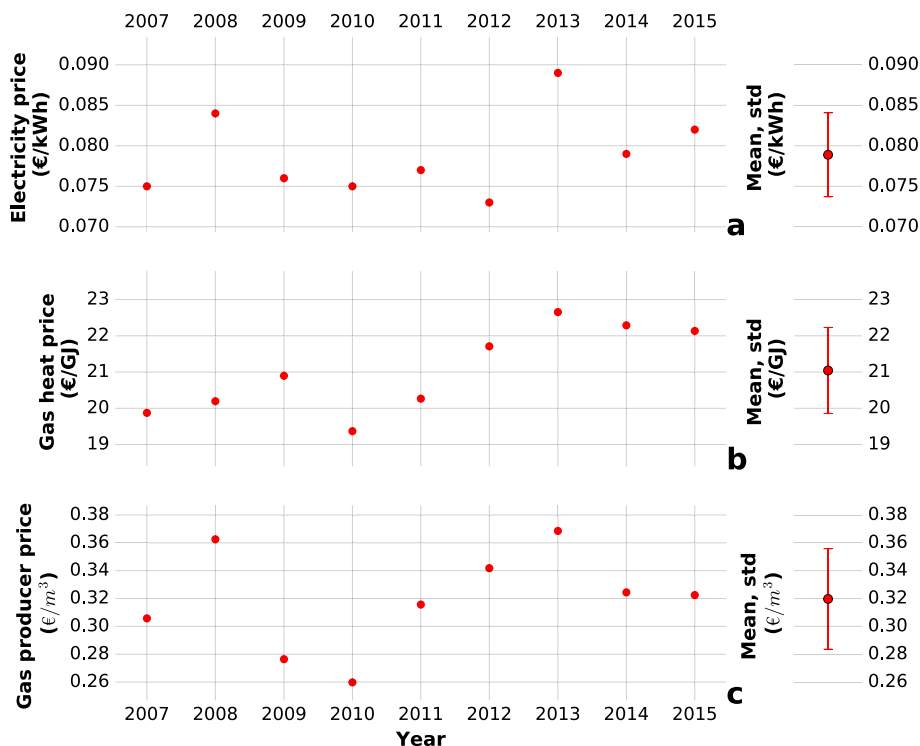


Fig. 5. Electricity prices for industrial use (a), gas generated heat prices (b) and gas producer prices (c). Data source [33].

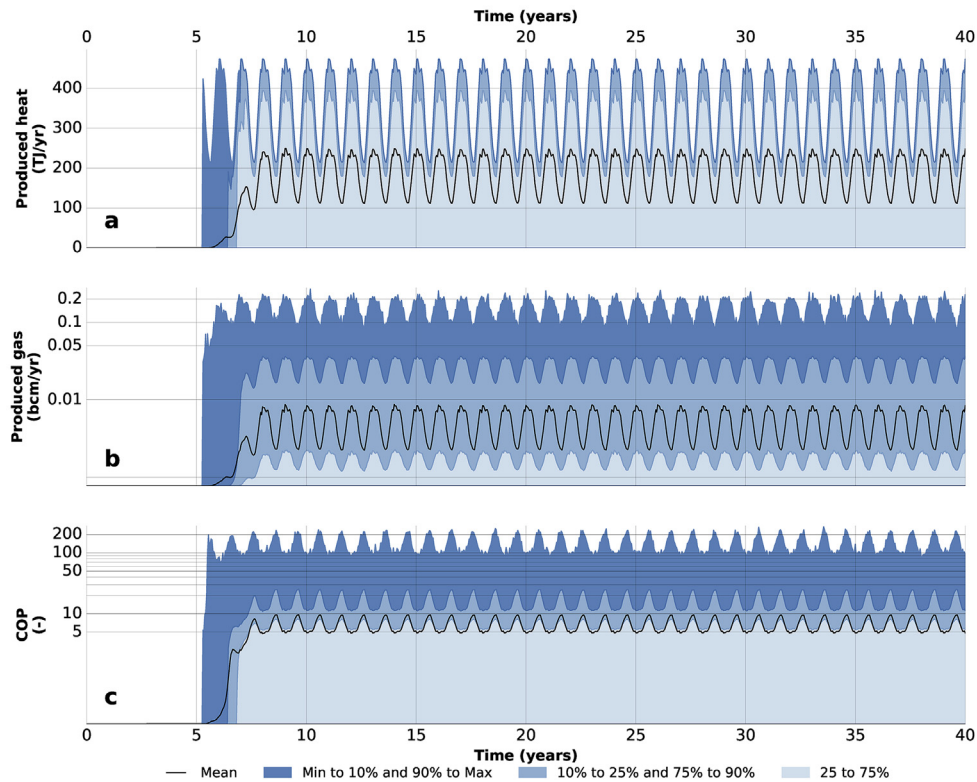


Fig. 6. Heat production per year (a), yearly gas production (b) and Coefficient Of Performance (COP), defined as the ratio of generated heat to pumping energy (c). Note that the scale on (b) and (c) is not linear.

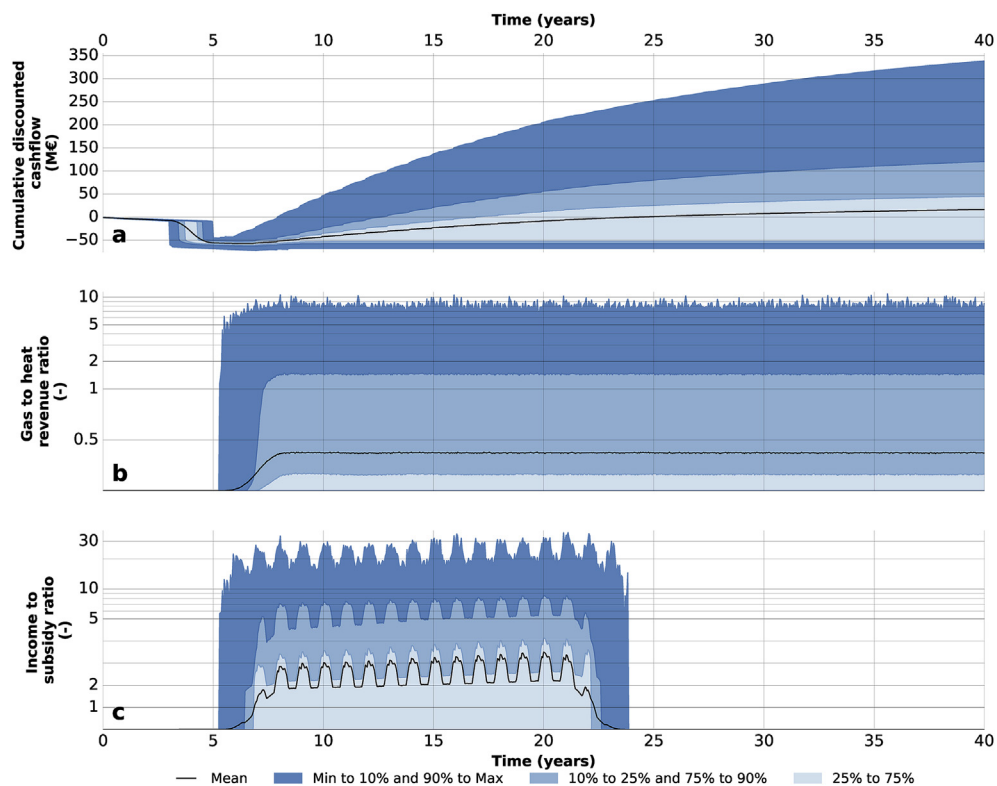


Fig. 7. Economic analysis with cumulative discounted cashflow (a), the ratio of gas revenues to heat revenues (b) and the ratio of income to subsidy (c) with their respective percentiles for 20,000 iterations. Note that the scale on (b) and (c) is not linear. The gas to heat revenue ratio does not include any income that might be generated as a result of subsidized heat generation; only the direct income from heat delivery is considered. The ratio of income to subsidy includes both heat and gas generated income.

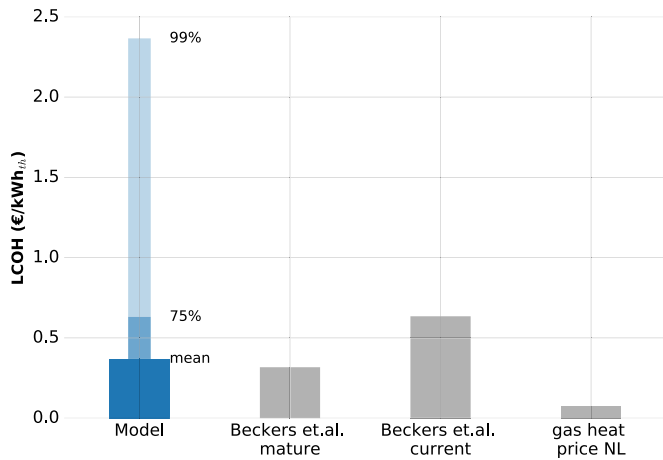


Fig. 8. LCOH index from the model compared to literature sources and gas heat price in the Netherlands.

presented in Appendix C. The COP of the system exhibits a mean value that varies seasonally between 5 and 10 (Fig. 6c), again demonstrating very thick percentiles between 90% and Max values. These wide percentiles are attributed to the impact of pressure depletion and reservoir permeability on the required pumping energy [24].

The narrow range of values in the 90% to Max percentile band for the heat production compared to the gas production (Fig. 6a&b respectively) can also better explain the percentiles of the economic parameters; gas production related uncertainty heavily affects the value range of the economic percentiles, despite the fact that heat revenues remain more important than gas revenues throughout the production time (see section 3.2).

3.2. Economic results

The cumulative discounted cashflow provides a comprehensive overview of the project finances taking into account all financial parameters and annuities. The mean includes all possible input variable values including the occasions for which any of the two wells has failed during drilling. A large decrease is observed during the construction phase before the first 5 years of production, after

which the cashflow starts to slowly recover as energy and income is generated. Under the most favorable conditions profitability is achieved around year 10, while the mean of the ensemble achieves profitability around year 27. The lower part of the range remains flat; this is caused by the failure of any of the two wells that ultimately leads to a project halt and no further economic calculations (see also section 2.2.2).

Once production has started, heat revenues contribute more than gas revenues to project finances (Fig. 7b); the mean ratio exhibits a heat generated income that is about 2.5 times more than that of gas generation. The sharp transitions of the index are attributed to the daily sampling interval of the gas production volumes (see Appendix B). Nonetheless and for all percentiles the ratio remains constant throughout the lifetime.

Once production begins the income to subsidy ratio is also computed for a period of up to 15 years following the initial production time (see also 2.4.5). The generated income remains the main source of revenue and is up to circa threefold larger than the provided subsidy (Fig. 7c). The seasonal load factor is clearly observed in the results (see also Fig. 3b); during periods of low load factors (i.e. centered around the summer period) the subsidy proves more important, as exhibited by the lower income to subsidy ratio. The larger peaks are attributed to the possibility to produce higher gas volumes together with the heat. The heat and gas income becomes progressively more important over subsidy as a revenue source; this is evident by the marginal upward trend of the mean over time within the 15 years for which the subsidy is available (Fig. 7c).

The LCOH index shows a mean value of 0.36€/kWh_{th}. This value is close to the projected LCOH of 0.32€/kWh_{th} (Fig. 8) of commercially mature district heating systems and almost half of the reported 0.63€/kWh_{th} for current technology [36]. Nonetheless, the LCOH remains fivefold more expensive than gas generated heat in the Netherlands (average value for years 2007–2015, see also Fig. 5) [32]. The cumulative discounted cashflow is also alternatively displayed by discriminating the iterations with both wells successful and those with any of the two wells having failed (Fig. 9a). The adjacent frequency histogram reveals that for both successful wells, most iterations are clustered in the interval with NPV's between zero and 50 M€, while for any failed well values are clustered slightly lower than –50 M€ (Fig. 9b). Part of the assemblage for the successful wells (circa 5%) still generates a negative NPV after 40 years. The Cumulative Distribution Function (Fig. 9c) reveals the

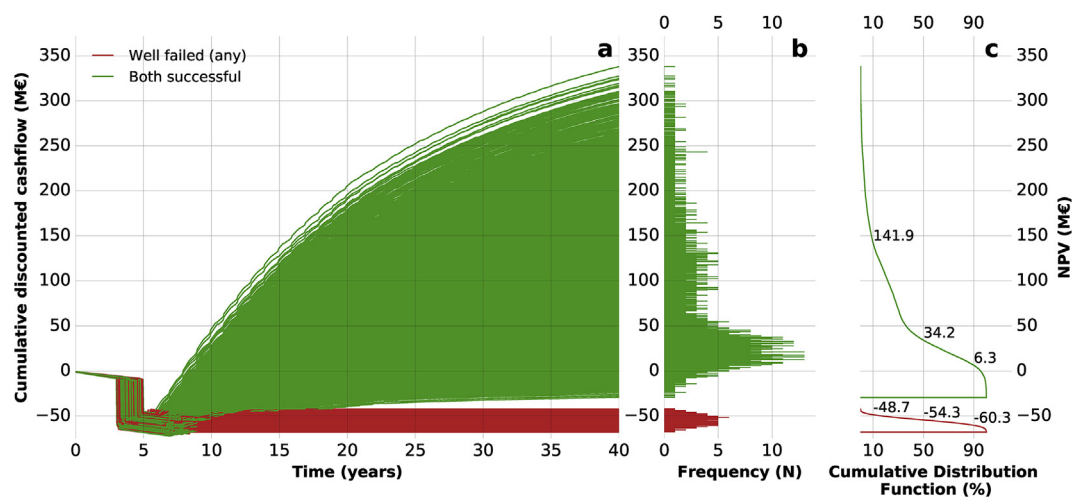


Fig. 9. Cumulative discounted cashflow of 20,000 iterations (a), their respective frequency histogram for the NPV at year 40 (b) and the Cumulative Distribution Function (CDF) at year 40 (c).

Table 2

Calculation of the EMV considering the CDF values of P10, P50 and P90 (10%, 50% and 90% probability) as presented in Fig. 9.

	Probability		
	P10	P50	P90
POS/(1-POS)	0.63/0.37		
NPV	141.9	34.2	6.3
COF	−48.7	−54.3	−60.3
EMV	71.4	1.5	−18.4

respective probability of occurrence for the two cases. The EMV values highlight that at 50% probability the project will yield marginal profit (Table 2), while at 90% probability the deficit will be greater than 8 M€. A positive value of 71 M€ or higher only has a 10% probability of occurring.

3.3. Sensitivity

The sensitivity analysis allows for a relative ranking of the input effects and their respective probability ranges or values. It should be noted that the POS of the wells is not part of the sensitivity analysis since by definition it does not exhibit a continuous value range and therefore would not yield a ranged outcome. The absence of the POS in the sensitivity analysis accounts for the slightly different central values for both the NPV and the LCOH compared to the mean values presented earlier (Figs. 7 and 8).

The importance of the load factor, indirectly reflected in the range of the effective flowrates, is the most dominant; higher flowrate can increase the NPV by more than threefold, while a lower one can decrease it down to deficit levels. This aspect highlights the importance of a carefully selected load factor profile throughout the year. The sensitivity of the NPV to the reservoir gas saturation is also prominent, with higher saturation leading to a higher NPV. The volume of gas can significantly affect the available income (Fig. 10). The fact that the NPV is more sensitive to heat production (directly related to flow rate level) compared to gas

corroborates the ratio of gas to heat income being lower than one (see Fig. 7).

The significance of the load factor and consecutively the flow rate is in line with previous findings where the flow rate level was the second most significant parameter to affect the NPV [22]; it should be noted that the considered system was different in several ways (most notably production temperature, drilling depth and well spacing).

For the next three inputs (discount rate, OpEx percentage, injection temperature) an increasing value leads to an NPV decrease. At the same time their influence range is almost symmetrical to the central value of the input range. The same can be said for the following four inputs (HT households, network length, gas heat consumer price and network cost). The ranking of the gas heat price which indirectly affects the price of the geothermal heat through the geothermal to gas heat price ratio (see also 2.4.5 and Table 1 Economics), together with that of the reservoir gas saturation, can explain the high values for the 90% to Max percentiles of the cumulative discounted cashflow results (Fig. 7). The network length and reservoir pressure depletion that follow have very similar influence ranges ($\pm 35\%$).

The LCOH sensitivity plot reveals a slightly different influence ranking of the inputs, since the LCOH is not affected by any gas related parameters (see also 2.4.1). The effective flowrate, which directly corresponds to the produced amount of heat, proves the most influential (Fig. 11) just like for the NPV. Higher flowrate reduces the LCOH by ~35% compared to the 50% increase it exhibited on the NPV index. This could be attributed to the fact that the NPV index also considers the revenues while the LCOH does not; therefore, since flow rate is related to the amount of heat generated and sold it has an impact on the revenues. Injection temperature follows, with an injection temperature of 40 °C increasing the extracted energy and thus reducing the LCOH by circa 20%. A lower injection temperature increases the extracted energy and the overall COP, thereby improving the ratio of expense to generated energy. The percentage of OpEx, reservoir permeability and transmission efficiency follow.

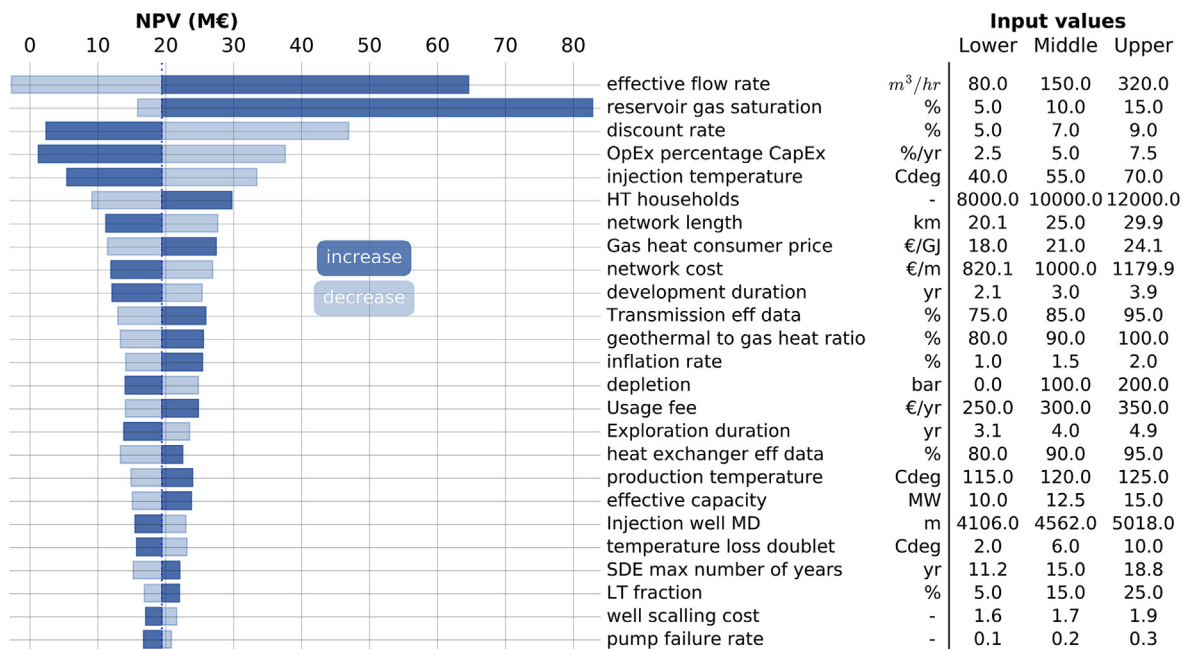


Fig. 10. Sensitivity analysis for the NPV index with respect to the model inputs in decreasing order of importance. The respective values of the NPV are shown on the left hand side, while the respective input ranges are denoted on the right hand side.

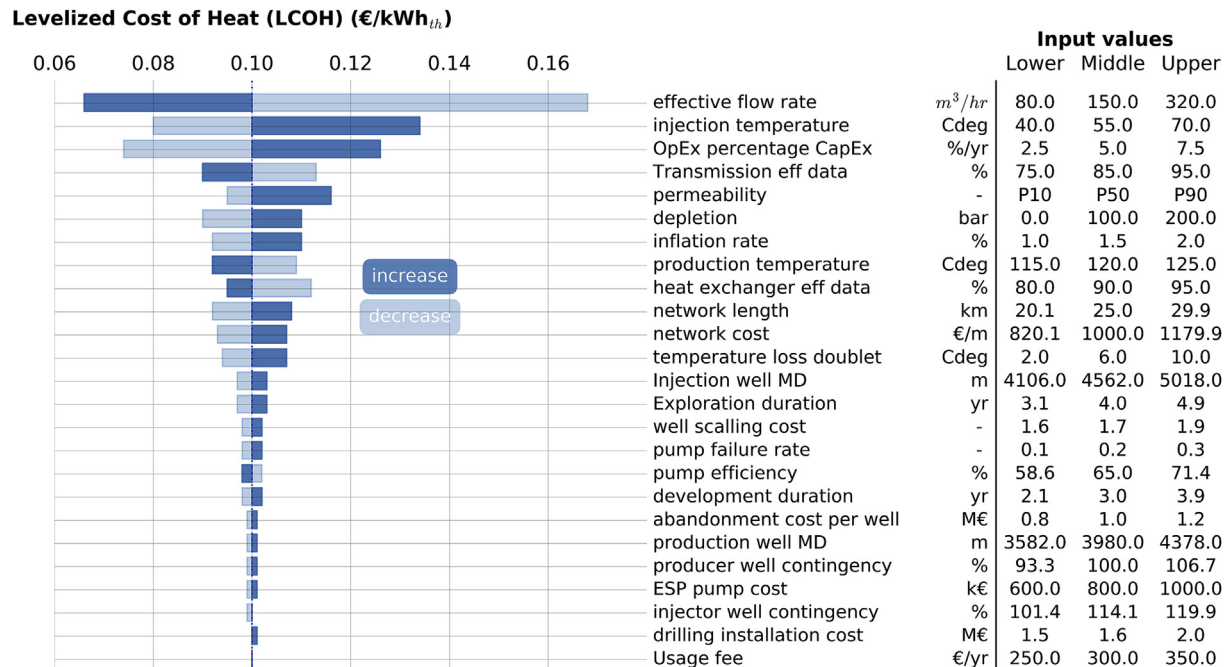


Fig. 11. Sensitivity analysis for the LCOH index with respect to the model inputs in decreasing order of importance. The respective values of the LCOH are shown on the left hand side, while the respective input ranges are denoted on the right hand side.

The OpEx percentage has the second highest potential to further reduce the LCOH after flowrate. Moreover, the OpEx percentage together with the inflation rate and network costs are the only economic parameters with a large influence in the LCOH; this highlights the fact that the LCOH index is mostly controlled by the operational, geological and technical aspects. The network cost and the temperature loss of the doublet complete the most significant influencing inputs, after which the impact becomes less significant.

4. Discussion

The presented techno-economic model enables a comprehensive understanding of the interplay between economic and technical uncertainty. The model uses probability distributions for most inputs addressing previously raised concerns with regard to capturing uncertainty in doublet capacity [22], and even goes beyond by employing a probabilistic approach in all aspects of the analysis. Therefore, the complexity and interdependence of the variables shaping the energetic output and economic performance of a direct use geothermal system is structured and analysed comprehensively. This is done through utilizing the understanding of geological and technical aspects of the geothermal system as the foundation, now combined with economic aspects. The analysis could be further fine-tuned when project or technical limitations are more sharply defined. Effectively, the insights from the analysis could be refined as the project advances and reservoir initial state, geological, operational and economic uncertainty are further reduced following the drilling of the exploration well.

When considering financial profitability, both the NPV and EMV results indicate that this remains a challenge. This is in contrast to the relatively competitive LCOH index generated through the 20,000 model iterations. This discrepancy, rooted in the fact that the LCOH index does not consider the revenues generated, highlights that using solely the LCOH as an economic indicator could be misleading. Considering the NPV and LCOH indexes together provides a more comprehensive understanding of the economic

outlook. However, the LCOH is still an insightful index for comparing energy generation costs from different sources. It should be noted that possible funding or taxing expenses could further deteriorate the financial outlook of such a project. Additionally, financial profitability seems to be more related to the possible gas production rather than the production of geothermal heat.

Nonetheless, the load factor remains extremely pertinent for improving profitability. Storage could reconcile discrepancies in the demand and supply balance on a seasonal basis, thus improving the effective load factor of system [25]; This however means that the energetic efficiency highlighted in previous research [25] is countered by the energy extraction rate (see chapter 3.3). Thus, a fine balance between resource efficiency and economic viability is required to ensure a profitable deployment of geothermal direct use utilization; for the Groningen data presented here the load factor must be such that it ensures flowrates above circa 100 m³/h to result in a positive NPV with all other variables being constant. This would require either a seasonal storage or additional load to the system for the lower load factor periods. Moreover, sequencing the network construction to follow the drilling of the well could reduce the exposure and financial risk; if the wells are successfully drilled then further investments could commence.

Furthermore, even though drilling costs were identified before as the most impactful to LCOH for geothermal projects, followed by plant lifetime [20], this claim can be challenged. Even though drilling costs together with the grid deployment costs remain the biggest capital expenditures, the LCOH index is mostly sensitive to operational (i.e. load factor and injection temperature), geological (i.e. permeability and depletion) and technical inputs (i.e. transmission and heat exchanger efficiency, network length and cost). This is in part because drilling and network deployment costs are not expected to become significantly lower, therefore, cost reduction options should be sought elsewhere. Inputs related to drilling costs (well scaling factor, drilling depth and well contingencies) rank low on the sensitivity analysis of both indexes; moreover, for the LCOH their influence is in the order of ~3–4% or lower.

Within the first ten most influential inputs to the LCOH the OpEx percentage and inflation are the only inputs of economic origin; consequently, the LCOH is not so heavily influenced by the economic context in which a project is deployed. On the contrary, for the NPV sensitivity the discount rate, OpEx percentage, gas heat price and inflation are encountered in the first ten influential inputs, implying that project profitability is more tightly linked to the deployment context.

Regarding the provided subsidy scheme in the Netherlands for deep geothermal projects, it would appear that the financial support provided is not sufficient to ensure a profitable outcome. While the generated income exceeds the provided subsidy amount, leading in principle to a healthy project, the projected outcome implies that under these conditions a project like this would not be realized (see also EMV and NPV). Therefore, the intended scope of the subsidy scheme could benefit from some revision, if the policy goal is to stimulate deep direct use geothermal projects. While the 15 year duration of the support scheme is generous, the cashflow curve suggests that a shorter but more substantial subsidy scheme would aid similar projects in overcoming the high amount of initial investments required. The amount of renewable, locally generated heat (a mean of ~250 TJ/year) is substantial enough from a regional scale perspective to be further pursued. A similar analysis for multiple projects from a bottom up perspective could be envisioned as complementary to the top-down economic analysis usually carried out in future research.

5. Conclusions

A probabilistic, techno-economic model for direct use, deep geothermal systems is introduced based on the insights of the Groningen geothermal project. The model makes use of previous work on initial state, geological and operational uncertainty [24] and incorporates the insights regarding resource efficiency and coupling a direct use geothermal system to heat networks [25]. Furthermore, the model considers economic uncertainty over a period of 40 years using 20,000 iterations.

The use of detailed 3D reservoir simulations allows for a robust estimation of the produced heat and gas from the geothermal system, with low uncertainty levels. The inclusion of the seasonal heat demand enables a more comprehensive evaluation of the COP and its importance and influence to the economic analysis.

The EMV results reveal a 50% chance of marginal profits over the period of 40 years and a 90% chance of an 18 M€ deficit. This distribution is mostly attributed to the probability of both wells being successfully drilled. Nonetheless, the analysis suggests that a small part of the iterations with both wells being successful could still yield a net deficit. Therefore, for the Groningen dataset profitability is challenging.

Drilling and network deployment costs remain the main capital expenditures but the sensitivity reveals that the NPV is mostly influenced by flow rate and gas saturation. Constructing the grid only after the wells are successfully drilled would reduce the economic risk. Additionally, since the NPV is strongly linked with the reservoir gas saturation levels (and consequently the gas volume produced), the produced gas uncertainty in combination with the price at which it is sold results in high values for the 90%–100% NPV percentiles.

Nonetheless, the NPV retains a high sensitivity to economic parameters related to the deployment context, such as discount and inflation rate; this is in contrast to the LCOH which is mostly affected by geological and operational parameters. It is therefore recommended to use both indexes when performing techno-economic analysis of deep geothermal projects.

The load factor of geothermal heat production emerges as the

second most important parameter affecting the financial outlook. In view of previous insights regarding resource efficiency through coupling supply and demand, a strong divide exists between a more sustainable development and economic profitability of deep, direct use geothermal systems in conductive settings. Since the load factor varies seasonally, the importance of seasonal storage or additional seasonal loads can significantly improve the economic outlook of such projects.

Lastly, the current Dutch subsidy scheme proves insufficient to overcome the challenging technical nature of this particular project. A support scheme with a shorter duration but more impact in the post-development phase would be more efficient in outweighing the high initial investment costs.

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Appendix A. Supplementary data

Supplementary data related to this article can be found at <http://dx.doi.org/10.1016/j.renene.2017.07.090>.

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